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(19) (CA) **APPLICATION FOR CANADIAN PATENT** (12)

(54) Sweep in Thermal for Using Emulsions

(72) Chakrabarty, Tapantosh - Canada ;
Tang, Joseph S. - Canada ;

(73) Esso Resources Canada Limited - Canada;

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ABSTRACT

Water-in-oil emulsions are injected into subterranean formations to divert steam from steam-swept zones around cyclic steam stimulation wells or between injection and production wells in steam floods. The emulsions divert hot fluids to cold unswept zones containing high oil saturations, thereby increasing the net oil recovery.

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APPLICATION FOR PATENT

INVENTORS: TAPANTOSH CHAKRABARTY and JOSEPH S. TANG

TITLE: IMPROVING SWEEP IN THERMAL EOR USING EMULSIONS

SPECIFICATION

Background of the Invention

1. Field of the Invention

The present invention relates to improved recovery of viscous oils from formations by steam processes. More specifically, a method of diverting steam from flooded-out portions of the formations to oil-containing portions of the formations by use of a water-in-oil emulsion is provided.

2. Description of Related Art

A substantial portion of the world's known reserves of hydrocarbons is in the form of oil having a very high viscosity under existing subterranean conditions. The viscosity is often such that the flow rate of the oil through wells is uneconomic using common oil industry techniques. The subterranean formation containing the oil is often too far below the surface of the earth to allow economic recovery by mining techniques. The only alternatives available for recovery of such oils employ wells and a technique to decrease the viscosity of the oil. The most common technique for decreasing viscosity of the oil is to increase its temperature, by processes referred to generally as thermal recovery. The most common thermal recovery processes are cyclic steam stimulation, steam

injection or hot water injection. In cyclic steam injection, steam in injected for a time into a well, then the well is converted to a production well and fluids are produced from that same well. Cyclic steam stimulation of wells in a field may be employed before a steam or hot water flood is used to drive fluids from injection wells toward spaced-apart production wells.

When steam or hot water is injected into the formation, it by-passes much of the oil-saturated rock because the injected fluid has much lower viscosity than the cold oil. A variety of efforts have been made to find fluids which can be economically injected to plug the swept-out region of the formation, where steam has displaced most of the viscous oil, and to divert steam which is injected thereafter to the cold or unswept portion of the formation.

Two types of fluids have been suggested for diverting the flow of injected steam from the portion of the formation which has been largely swept of its oil and into more oil-saturated portions. These fluids are foams and oil-in-water emulsions. Foams are disclosed, for example, in U.S. Patent 4,607,695. A mixture of steam, a non-condensible gas and a surfactant is injected into the formation. A foam which has a higher apparent viscosity than steam is formed in the pore spaces of the rock to block the flow of steam and divert steam from the swept zones. U.S. Patent 4,609,044 discloses a process for recovering acidic viscous oil by injecting steam along with dissolved alkaline salt and surfactants for foaming the steam. The use of emulsions for diverting steam flow in thermal recovery processes has been discussed in SPE Paper No. 15052, "Use of Emulsions for Mobility Control During Steamflooding," by T.R. French et al. These studies were related to oil-in-water emulsions, both those produced _in situ_ and those injected into wells. U. S. Patent 4,161,218 discloses the use of a coarse

oil-in-water emulsion formed in the pore spaces by a surfactant injected in an injection fluid. The oil droplets in an oil-in-water emulsion plug pore throats, thereby diverting steam into unswept portions of the formation.

U.S. Patent 4,444,261 discloses a method of diverting steam flow in an oil recovery process by injecting into a formation a slug of high molecular weight hydrocarbon which has been heated to a high temperature. The diverting hydrocarbon then cools and increases in viscosity to divert the following steam.

While many suggestions have been proposed for diverting fluids, there remains the problem of achieving greater sweep of formations containing high viscosity oil in thermal recovery processes employing cyclic steam stimulation, hot water flooding or steam flooding. A diverting fluid is needed which is low in cost, stable in the formation at high temperatures, and which is compatible with formation fluids.

Summary of the Invention

According to one embodiment, there is provided a method of increasing recovery of viscous oils in a thermal recovery process by following injection of steam with an emulsion of water in oil. In another embodiment, the water-in-oil emulsion is heated on the surface before it is injected. In yet another embodiment, the oil and water are injected separately or in the form of an oil-in-water emulsion and converted into a water-in-oil emulsion in the wellbore. The emulsion is preferably stabilized by adding an alkaline material to the water which reacts with acidic components in the oil. Alternatively, the emulsion is stabilized by an added effective surfactant. The emulsion is preferably formed from the viscous oil recovered from the formation. The emulsion diverts steam or hot water injected after the emulsion is

injected to unswept portions of the formation containing viscous oil and increases oil recovery in a more economical means than hitherto available.

Brief Description of the Drawings

Fig. 1 is a graph of the ratio of oil recovered to the oil in place and of the oil-to-steam ratio in a parallel pack model of steam injection with and without injection of a slug of water-in-oil emulsion.

Fig. 2 is a graph of oil-to-steam ratio prior to and following injection of a slug of water-in-oil emulsion in a three-dimensional packed model of a steam injection process.

Description of Preferred Embodiments

In steam recovery processes, it is common to inject a predetermined amount of steam into a formation containing viscous oil through an injection well penetrating the formation and then to produce steam, hot water and oil back through the same well in a process called cyclic steam stimulation. This process is commonly practiced before a steam flood operation. In a steam flood operation, steam is injected into the injection well or wells and oil, water and sometimes steam are produced from a production well or wells which are spaced apart a selected distance from the injection well or wells. The purpose of the cyclic steam stimulation process is to establish flow communication between the wells such that the formation can be flooded with steam to recover the oil in the formation between the wells. When steam breaks through into the production wells, however, the steam zone often occupies only a small portion of the vertical extent of the formation, the steam having moved along the top of the formation or through more permeable streaks in the formation. A slug of viscous fluid can then be injected into the zone where steam has swept

oil from the formation to partially block flow of steam into this zone and cause the steam to be diverted. The efficacy of such a slug injected into the steam-swept zone will be manifest by an increase in the oil production rate at production wells.

Steam flooding processes are normally studied in the laboratory by constructing scaled models of a subterranean formation. In many formations, a fracture in the formation is formed by injection of steam. Steam can then channel through the fracture and establish more rapid flow communication between injection and production wells. In other formations, a highly permeable streak in the formation has an effect on fluid flow during steam injection similar to a horizontal fracture. These effects of fractures and permeable streaks occur in cyclic steam stimulation and in flooding processes. These situations can be modeled in the laboratory to study the benefits of a viscous slug of water-in-oil emulsion in flooding process.

Many crude oils in their natural state contain organic acidic components. The amount of acid present is measured as an "acid number," which is defined as the number of milligrams of potassium hydroxide required to neutralize all the acidic components in 1 gram of oil. These organic acids will react at an oil-water interface with alkaline components in the water phase to produce soaps, which are surface active at the oil-water interface and which can serve to stabilize emulsions. We have found that with the proper ionic composition of the water phase and with high shear energy applied, a water-in-oil emulsion can be formed with crude oil which is stable even at the high temperatures which exist in steam floods. Water-in-oil emulsions made with viscous oil are several times more viscous than the oil, and several orders of magnitude more viscous than steam. Surprisingly, this type of emulsion was shown to be effective in models of steam

flooding processes to substantially increase the net oil recovered in a steam flood. Alternatively, emulsifiers for stabilizing water-in-oil emulsions at high temperature are added to the oil. Examples of such emulsifiers are alkyl aryl sulfonates and alpha-olefin sulfonates.

For example, a water-in-oil emulsion for diverting steam can be created using viscous crude oil which has a viscosity in the range from about 900 cp to about 1100 cp at a temperature of 60° C. and an acid number of 1.1 mgm KOH per gm oil, and using water that contains from about 100 ppm to about 2000 ppm sodium hydroxide, 10,000 ppm sodium chloride, 80 ppm calcium ion and 24 ppm magnesium ion. Chlorides of other monovalent ions such as potassium and ammonium can be substituted for the sodium chloride. The [illegible] of concentration of sodium chloride in the water phase is preferably from about 500 ppm to about 100,000 ppm. The optimum concentration will depend on the composition of the oil phase, the acidic components naturally present in the oil phase, the amount of other ions present and the relative amounts of oil and water in the emulsion. The water phase preferably contains a sufficient amount of divalent ions such as calcium and magnesium to further stabilize the emulsion. The divalent calcium and magnesium ions can be supplied by any soluble salt containing these elements. The optimum concentration of divalent ions will depend on the amount of sodium or other monovalent ion present, the composition of the oil phase, temperature and the relative amount of oil and water present in the emulsion. The concentration of divalent ions will preferably be in the range from about 10 ppm to about 1,000 ppm. Other alkaline materials would be suitable substitutes in equivalent amounts for the sodium hydroxide, such as hydroxides of ammonium, potassium,

calcium and magnesium. Alkaline silicates would also be suitable.

The initial water content of the emulsion is preferably in the range from about 5 per cent to about 70 per cent by volume. More preferably, the initial water content is from about 20 per cent to about 50 per cent by volume. Emulsion stability experiments can be performed to determine the amount of water remaining in the water-in-oil emulsion after different times the emulsion is maintained at the steam temperatures of interest, with different compositions of the water phase and using the oil to be injected in the emulsion. The composition of the water phase is preferably varied until at least about 50 per cent of the initial water present remains in the emulsion after one week at steam temperatures.

An important feature of our invention is that the emulsion can be repeatedly injected in slugs during the cyclic steam stimulation or steam flooding process. Thus, while the emulsions formed are not completely stable with time at steam temperatures and lose a part of the water by demulsification, they are inexpensive to prepare and are sufficiently stable to allow diversion of the steam for an adequate time to achieve substantial benefits in oil recovery.

The emulsions are preferably heated before injection, by heating the component fluids on the surface of the earth either before or after the emulsification step. After heating, the emulsion then has low enough viscosity to be injected into the injection well or wells. The emulsion is sufficiently stable and the water content is high enough to significantly increase the viscosity of the emulsion over that of the oil phase. For the same slug size, emulsion is less expensive than oil since a lower volume of oil is injected.

Emulsification is preferably achieved by imparting high shear conditions to a mixture of oil and water. Satisfactory emulsification can be achieved at the surface by centrifugal blade devices, by flowing the fluids at high pressure through jets, or by other emulsification methods commonly used in industry. Alternatively, the emulsions can be formed by imparting high shear to the oil and water after the fluids have been pumped down an injection well. In another alternative method, part or all of the oil and water are formed into an unstable oil-in-water emulsion at the surface by adding the oil to an excess amount of water phase and the water-in-oil emulsion is then formed by high shear imparted in the wellbore or as the unstable emulsion flows through perforations in the casing of the well and into the formation. The amount of shear imparted to the fluid should preferably be such that the water droplets in the emulsion are smaller than the pore spaces of the formation swept by the steam so as to achieve sufficient stability of the emulsion and to allow the emulsion to flow through the formation as a viscous fluid.

In some fields, water-in-oil emulsion will be produced from at least some wells. This emulsion may be suitable for injecting as a slug in the method of this invention. Alternatively, the produced emulsion can be mixed with additional water and a suitable emulsion can be formed as described before.

Example 1

An emulsion was prepared using crude oil from the Cold Lake field, the crude oil having a viscosity of 1000 cp at a temperature of 60° C. The emulsion contained 39 per cent aqueous phase, the aqueous phase containing 750 ppm sodium hydroxide, 10,000 ppm sodium chloride, 80 ppm calcium ion and 24 ppm magnesium ion. The emulsion was formed by heating the fluids to 60° C.

and forming the emulsion in a Waring blender, a centrifugal blade device well-known for use in a laboratory. The average size of the water droplets in the emulsion was 1 micrometre. The viscosity of the emulsion was 7,000 cp at a temperature of 60° C. When heated to 85° C., the emulsion could easily be injected into a sand-pack having a permeability of 2 darcies, which is about the permeability of the Cold Lake formation sand in many areas. The pore size of such sand is about 20 micrometres, so water droplets of the size produced will flow through the pore spaces of such a sand as a fluid. Because the water is not in contact with the sand surface when in the form of such fine droplets, the chemical reaction between the alkali in the water and components of the sand is expected to be greatly reduced, thus improving the stability of the emulsion in the formation. In stability tests of the emulsion in a pressure vessel, the water content of the emulsion was still over 35 per cent after one week at 250° C.

Two sand packs were prepared having a permeability of about 2 darcies. The two packs were insulated and heated to 95° C. Both packs were saturated with Cold Lake crude oil and connate water. One pack was individually flooded with steam to simulate a steam-swept zone. A steamflood in the combined parallel pack provided the base case. Then steam floods at 140° C. in the parallel pack were conducted. An emulsion slug equal in volume to 10 per cent of the pore volume of the steam-swept pack was injected. The emulsion contained 40 per cent brine and 60 per cent Cold Lake crude oil or bitumen.

Referring to FIG. 1, curve 2 shows the oil recovery ratio for the flood with the emulsion slug. Curve 4 shows the oil recovery ratio for the base case flood. Curve 12 and 14 show the oil steam ratio for the flood with the emulsion slug and the base case,

respectively. Oil recovery ratio is defined as the fraction of the initial oil-in-place recovered. Oil steam ratio is defined as the volume of oil recovered divided by the volume of water converted to steam and injected. It is apparent from FIG. 1 that the emulsion slug resulted in significantly higher oil recovery ratio and a higher oil steam ratio over most of the process. Detailed examination of FIG. 1 shows that the emulsion slug resulted in a 35 per cent improvement (after subtracting the volume of oil in the emulsion slug) in oil recovery in 30 per cent less time over the base case. The cumulative oil steam ratio of the emulsion slug flood in the first 90 minutes was 0.25 after deducting the amount of oil injected in the emulsion slug, compared with 0.14 in the first 120 minutes for the base case. The emulsion slug thus resulted in more efficient utilization of the injected steam.

Example 2

A scaled three-dimensional model of a subterranean oil-productive formation was used. The model was 56 cm in diameter and 38 cm in thickness. It was packed with sand having a permeability of 180 darcies and a porosity of 42 per cent, to scale a formation with a permeability of 2 darcies. The model contained two wells on opposite sides of the center to simulate an injector and producer well-pair. Wire mesh was placed at each well to simulate a horizontal fracture extending about 40 per cent of the distance to the other well. The model was saturated with 79 per cent pore volume crude oil, 11 per cent pore volume connate water and 10 per cent pore volume gas. The inclusion of a gas phase provided the high compressibility required for early cycle steam injection. Just prior to the beginning of steaming, a slug of water was injected.

Referring to FIG. 2, the oil steam ratio is shown at different times. First, two cycles of cyclic steam stimulation were conducted at each well. The oil steam ratios for the first and second cycles are shown at point 1 and point 2, respectively. The cyclic steam stimulation cycles were conducted to establish thermal communication between wells. The simulated horizontal fracture helped distribute the steam and set up a thermal communication channel between the wells, a scenario expected in many subterranean formations. Steam at 500 psig was injected into each well until the model reached injection pressure, then each well was produced until pressure and fluid rate were low. After two cycles of steam stimulation, thermocouple measurements in the model showed the wells were in thermal communication. The wells were then shut in for 8 minutes and a steam flood was then initiated in one well. The oil steam ratio for this flood is shown at curve 3 in FIG. 2. The model was then shut-in again for about 7 minutes and a second steamflood was initiated which lasted for 38 minutes, about the same as the first steamflood. The oil steam ratio for this flood is shown at curve 4 in FIG.2. Then a slug of water-in-oil emulsion was injected, the emulsion being heated to 80° C. before injection. The time of injection of emulsion is shown by area 10 of FIG. 2. A third steamflood was then initiated, this flood lasting about 100 minutes. The oil steam ratio for this flood is shown at curve 12 in FIG. 2.

The emulsion contained 40 per cent by volume brine, the brine containing 750 ppm sodium hydroxide, 10,000 ppm sodium chloride, 80 ppm calcium and 24 ppm magnesium. The emulsion was formed by blending the crude oil and water for 20 minutes until the average water droplet size was 1.5 micrometres. Emulsion viscosity was 5100 cp at 60° C.

Referring to FIG. 2, it is apparent that the oil steam ratio decreased during the cyclic steam stimulations and continued to decrease with time during the steamfloods. Injection of the emulsion slug at 10 is seen to have a dramatic effect in increasing the oil steam ratio in Curve 12.

The extrapolated decline curve of oil steam ratio before injection of the emulsion slug is shown at curve 16. The extrapolated decline curve of oil steam ratio after injection of the emulsion slug is shown at curve 14. Curve 18 is the value in the model of the oil steam ratio corresponding to the economic cutoff value, or the minimum oil steam ratio that will allow continued economic production in the formation. The cutoff value in the model of 0.26 corresponds to an oil steam ratio in the formation of 0.15. Using these three curves, incremental oil recovered by injection of the emulsion slug (subtracting oil injected in the emulsion slug) was estimated. The result was a total recovery of 23.3 per cent of the original oil in place for the emulsion slug process, compared with only 15.7 per cent without the emulsion slug. This represents an increase in oil recovery of about 25 per cent over the recovery for steamflood alone.

The invention has been described with reference to its preferred embodiments. Those of ordinary skill in the art may, upon reading this disclosure, appreciate changes or modifications which do not depart from the scope and spirit of the invention as described above or claimed hereafter.

THE EMBODIMENTS OF THE INVENTION IN WHICH AN EXCLUSIVE PROPERTY OR PRIVILEGE IS CLAIMED ARE DEFINED AS FOLLOWS:

1. A method for improving recovery of viscous oil following injection of steam into a subterranean formation penetrated by at least one injection well having a wellbore and at least one spaced-apart production well, the wells being in fluid communication, comprising:

(a) injecting steam into the formation through the injection well, thereby forming a steam-swept zone in the formation;

(b) injecting a slug of water-in-oil emulsion into the formation following steam injection; and

(c) thereafter resuming steam injection and recovering fluids from the formation through the production well.

2. The method of claim 1 wherein at least a part of the slug of water-in-oil emulsion injected into the formation is heated before injection.

3. The method of claim 1 wherein the water-in-oil emulsion injected into the formation is formed in the wellbore of the injection well by simultaneous injection of separate streams of water and oil.

4. The method of claim 1 wherein the water-in-oil emulsion injected into the formation is formed after the water and oil leave the wellbore of the injection well from the inversion of an oil-in-water emulsion.

5. The method of claim 1 wherein the water-in-oil emulsion injected into the formation is produced from a production well.

6. The method of claim 1 wherein the water-in-oil emulsion injected into the formation is formed by adding water to a water-in-oil emulsion produced from a production well.

7. The method of claim 1 wherein the water-in-oil emulsion injected into the formation is stabilized by adding an alkaline material to the water to react with an effective amount of acidic components in the oil.

8. The method of claim 7 wherein the alkaline material is selected from the group consisting of ammonium, sodium, potassium, calcium and magnesium hydroxide and a combination thereof.

9. The method of claim 8 wherein the alkaline material in the water is sodium hydroxide and the concentration is in the range from about 0.025 to about 0.075 per cent by weight.

10. The method of claim 1 wherein the water-in-oil emulsion is stabilized by at least one surfactant selected from the group consisting of alkyl aryl sulfonates and alpha-olefin sulfonates and combinations thereof.

11. The method of claim 1 wherein steps (b) and (c) are repeated at least one time.

12. The method of claim 1 wherein the water droplets in the emulsion injected into the formation have an average diameter less than about 2 micrometres.

13. The method of claim 1 wherein the oil phase of the water-in-oil emulsion is comprised of crude oil produced from the formation in which steam is injected.

14. A method for improving recovery of viscous oil following injection of steam into a subterranean formation penetrated by at least one well having a wellbore, comprising:

(a) injecting steam into the formation through a well, thereby forming a steam-swept zone in the formation;

(b) injecting a slug of water-in-oil emulsion into the formation through the well;

(c) resuming steam injection into the well; and

(d) thereafter recovering fluids from the formation through the well.

15. The method of claim 14 wherein at least a portion of the slug of water-in-oil emulsion injected into the formation is heated before injection.

16. The method of claim 14 wherein the water-in-oil emulsion injected into the formation is stabilized by adding an alkaline material to the water to react with an effective amount of acidic components in the oil.

17. The method of claim 14 wherein the water-in-oil emulsion is stabilized by at least one surfactant selected from the group consisting of alkyl aryl sulfonates and alpha-olefin sulfonates and combinations thereof.

18. The method of claim 14 wherein the water droplets in the emulsion have an average diameter less than about 2 micrometres.

19. The method of claim 14 wherein the oil phase in the water-in-oil emulsion is comprised of crude oil from the formation where steam is injected.

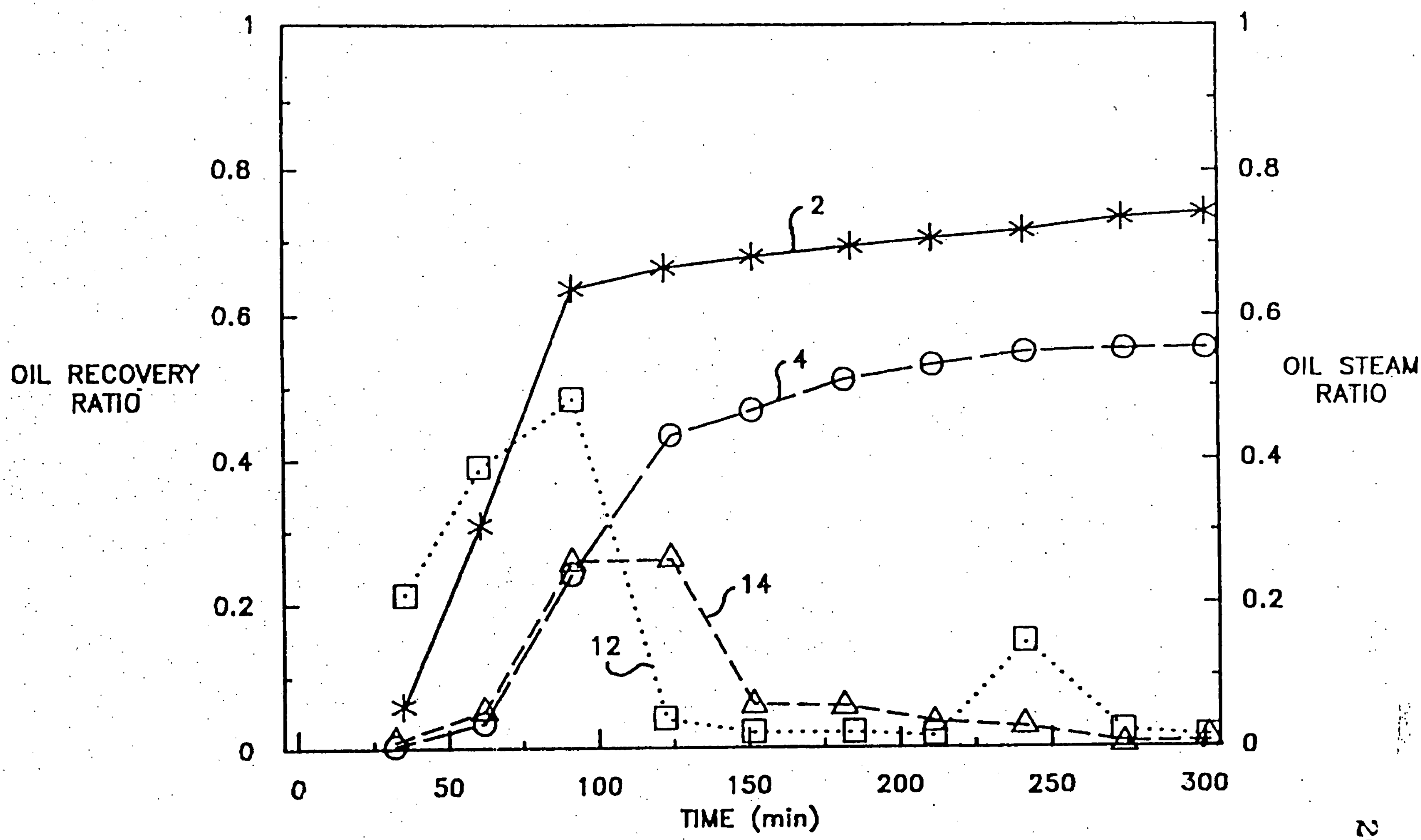

FIG. 1

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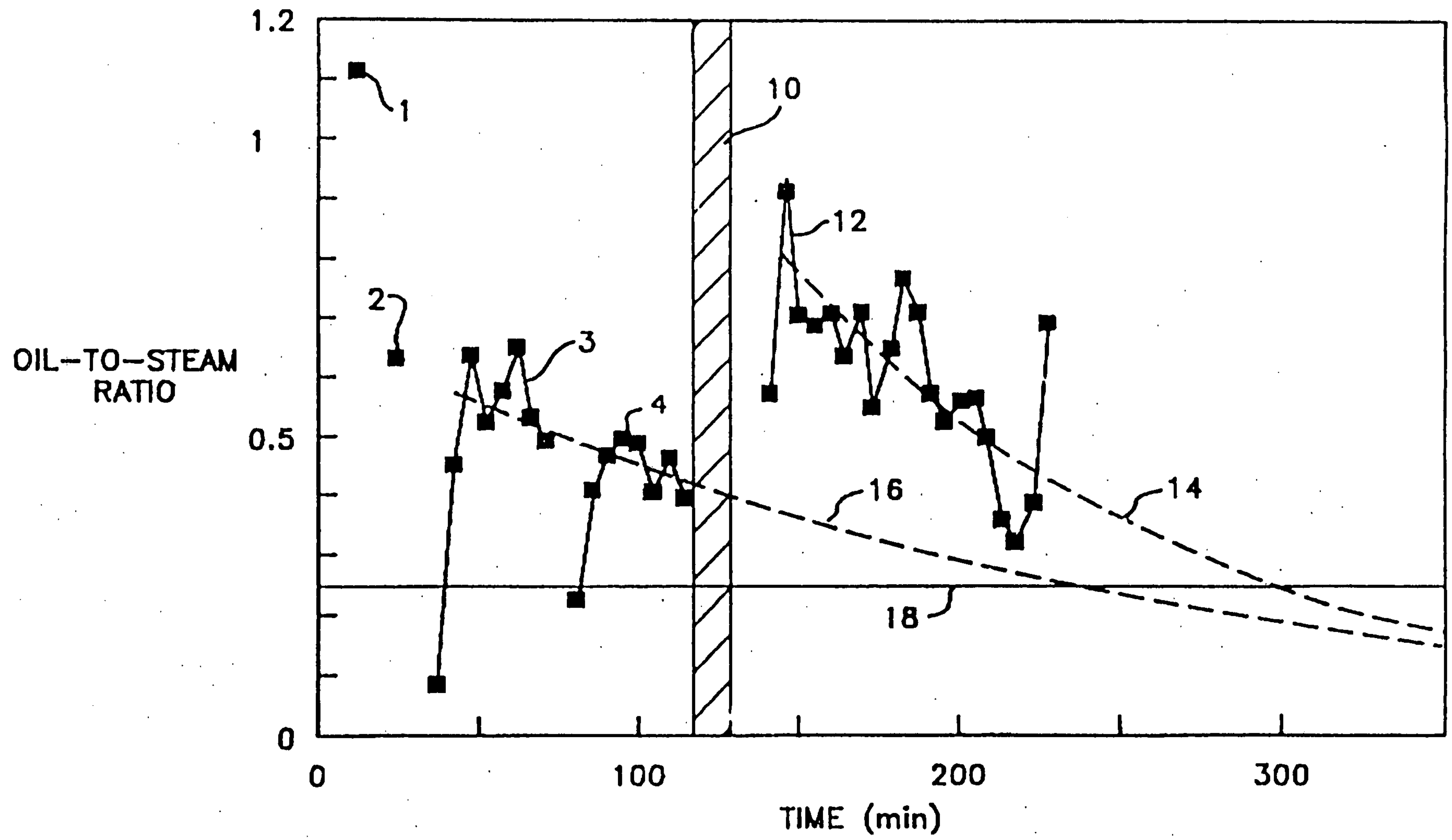
1.2
1
0.5
0
OIL-TO-STEAM RATIO
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100
200
300
TIME (min)
1
2
3
4
10
12
14
16
18

FIG. 2

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